PACIFIC NORTHERN GAS LTD.

ANNUAL REPORT 2002

CORPORATE PROFILE

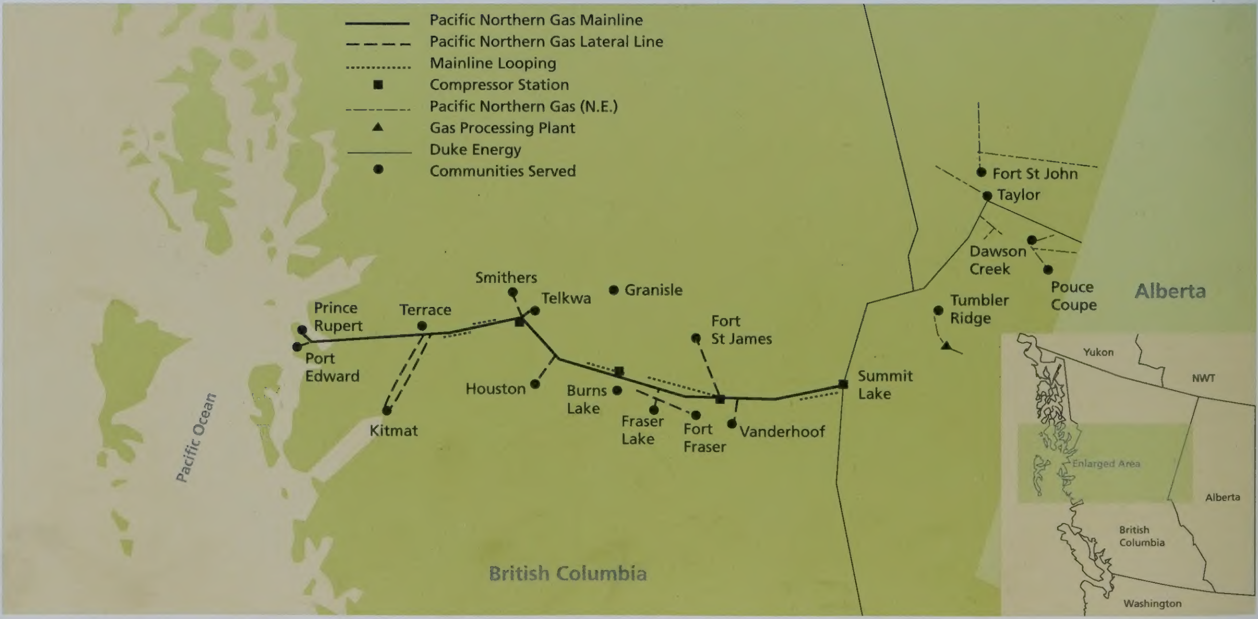
Pacific Northern Gas Ltd. delivers natural gas to customers in west-central British Columbia, and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast.

Pacific Northern's transmission pipeline is connected to the Duke Energy (formerly Westcoast Energy) system near Summit Lake, British Columbia and extends 587 kilometres to the west coast. Service is provided to some 23,000 customers including a number of large industrial operations. In addition, propane vapour distribution is provided in the community of Granisle.

Pacific Northern Gas (N.E.) systems serve some 16,000 customers in the Fort St. John, Dawson Creek, and Tumbler Ridge areas. Gas supply is received at a number of locations within the Fort St. John service area. In the Dawson Creek area the Company's transmission pipeline is used to transport gas from the Duke Energy system. In Tumbler Ridge the Company operates its own gas processing plant.

Pacific Northern's head office is located in Vancouver, British Columbia. Customer care and administrative functions are supported from a regional centre in Terrace. In addition, personnel responsible for customer service and system construction, operation and maintenance are stationed in nine communities located within the Company's service area.

MAP OF OPERATIONS



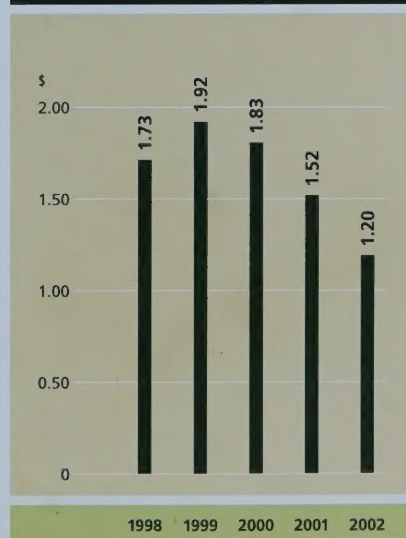
COMPARATIVE FINANCIAL HIGHLIGHTS

Years ended December 31	2002	2001	2000	1999	1998
Total energy delivered (TJ)	**39,463**	31 781	34 771	42 577	38 787
Net income (000)	**$ 4,590**	$ 5,715	$ 6,838	$ 7,125	$ 6,454
Earnings per common share	**$ 1.20**	$ 1.52	$ 1.83	$ 1.92	$ 1.73
Dividends paid per common share	**$ 0.00**	$ 0.00	$ 0.56	$ 1.12	$ 1.10
Total investment in utility plant (000)	**$ 177,314**	$ 179,301	$ 183,351	$ 182,917	$ 180,224

BUSINESS HIGHLIGHTS

- Pacific Northern's net income was $4.6 million in 2002, compared with $5.7 million in 2001.
- After providing for preferred share dividends, earnings per common share in 2002 were $1.20 compared with $1.52 in 2001. No common share dividends were paid in 2002 or 2001.
- Pacific Northern completed a $15-million financing in December 2002, allowing for the payment of a special common dividend of $2.75 per share in January 2003.
- Gas deliveries during the year increased to 39.5 petajoules, compared with 31.8 petajoules in 2001.
- Additions to property, plant and equipment totalled $6.0 million in 2002, compared with $3.8 million in 2001.

EARNINGS PER COMMON SHARE



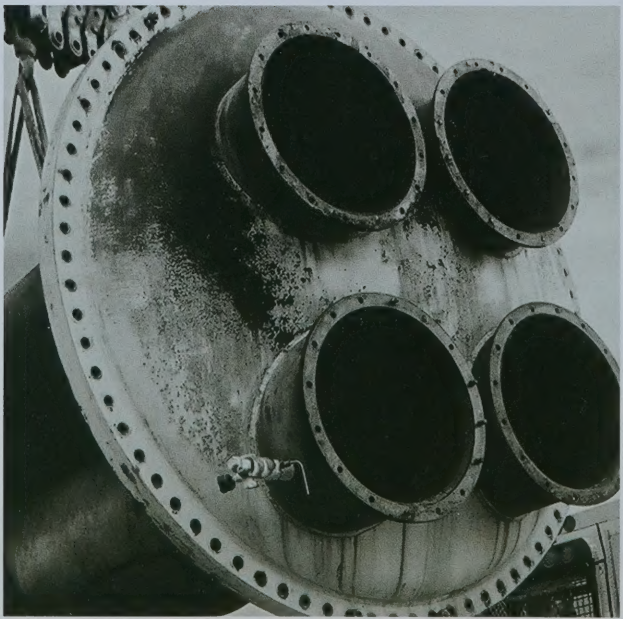
REGULATION: THE NATURAL FACTS

Pacific Northern Gas is subject to regulation under the Utilities Commission Act of British Columbia. The British Columbia Utilities Commission ("the Commission") regulates the business of the Company, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas, and the terms and conditions of service.

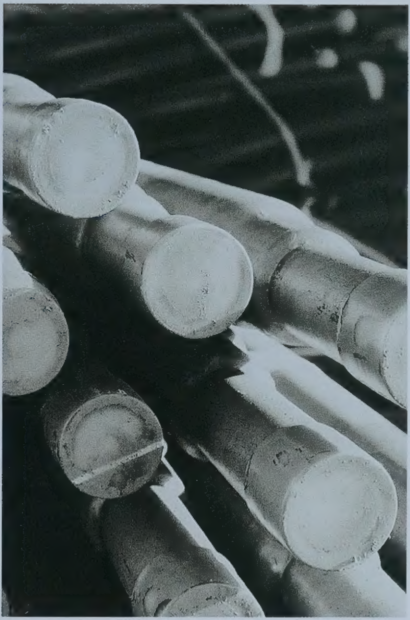
In approving rates, the Commission must ensure that the rates reflect a fair and reasonable charge for service of the nature and quality furnished to customers. The rates should be sufficient to enable Pacific Northern to earn a fair and reasonable compensation for its services and a fair and reasonable return upon the value of its property.

The Commission determines customer rates using a fixed rate approach on the basis of forecasts of both the cost of service and the volumes of gas delivered through the transmission and distribution systems. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the sum of the depreciated cost of property, plant and equipment that is used or useful in serving Pacific Northern's customers, plus a reasonable allowance for working capital. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

Revenue requirements applications for all service areas are submitted to the Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers and the Company under alternate dispute resolution processes supervised by Commission staff.



GAS SUPPLY: THE NATURAL FLOW



All of Pacific Northern's residential customers, most of its commercial customers and a number of its small industrial customers purchase gas from the Company at rates which include the gas commodity cost and the Company's cost of delivering gas to the customers' premises. The gas commodity cost paid by the Company to its gas suppliers is passed through without mark-up to customers.

The Commission reviews the gas commodity portion of Pacific Northern's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by the Company from those included in current retail rates are deferred for subsequent refund to, or recovery from, customers. To moderate the variability of the gas supply commodity prices paid, the Company uses financial instruments under a gas price risk management plan that is filed with the Commission on an annual basis.

A gas supply contracting plan is also prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The Company purchases gas from gas producers under long-term and short-term gas purchase contracts. The gas contracting plan is designed to ensure the Company has adequate gas supplies at reasonable prices to meet the requirements of its customers on the coldest day of the year, normally referred to as the peak day. Contracted gas that is surplus to customer requirements is sold into other markets at prevailing market prices. Most of the Company's contracted gas supply is produced in British Columbia.

The Company's large industrial customers, the majority of its small industrial customers, and a few large commercial customers arrange for delivery of their gas supply requirements to the Company. These customers contract for gas transportation service on the Company's pipeline systems. From time to time, some of these customers also purchase gas from the Company to supplement their own purchases, subject to gas supply availability from the Company.

EMERGENCY RESPONSE: THE NATURAL RESPONSE

Pipeline emergencies are rare, but they can occur. Pacific Northern Gas Ltd. takes its responsibility for pipeline safety seriously. Preparedness means developing integrated response plans based on open communication and teamwork. Pacific Northern ensures that local fire and police services have the information they require to deal with emergencies. The Company holds regular training exercises each year to keep employee skills fresh.

Pacific Northern utilizes Duke Energy's 24-hour per day Gas Control Centre to control and monitor the operation of its pipeline system. The computer-based SCADA (Supervisory Control And Data Acquisition) system in Vancouver allows pipeline operations staff to monitor pipeline flow, pressure conditions and trends, to start and stop compressor units, and to open or close pressure control valves. The SCADA system is capable of detecting and correcting various events that could impact system integrity. Unusual conditions trigger instrument alarms and field employees are called out to verify problems and take corrective action if necessary.

When an emergency occurs, Pacific Northern's emergency response plan immediately goes into effect. The Company's emergency centre is activated to coordinate the response to the event. Pacific Northern and local emergency response agencies work as a team to identify and solve the problem. The first notification of an upset in the pipeline system is generally from the Vancouver Gas Control Centre. Immediate notification of local Pacific Northern emergency response personnel and an initial assessment of the problem follow. Personnel are able to shut down various sections of the pipeline remotely, while trained emergency response crews travel to the site to repair the damaged pipe. All of this activity takes place with a focus on public and employee safety while minimizing any impact on customers. Pacific Northern works to quickly notify its large industrial customers of any pipeline emergency to ensure the impact on their operations is minimized. This close communication provides benefits to not only the industrial customers, but also any other customers that may potentially be affected by the emergency. After completing the repair, the system is returned to normal operation and the Company resumes regular levels of service to its customers.

ROBERT F. CHASE, CHAIRMAN

ROY G. DYCE, PRESIDENT AND CEO

Pacific Northern Gas was successful in meeting a number of challenges during 2002. In the last twelve months the Company successfully negotiated a new seven-year contract with Methanex Corporation, completed a $15-million financing, secured a short term line of credit with a new operating lender, significantly improved the efficiency of the Company's call center and other centers of operation, and, in early 2003, successfully negotiated a settlement with customers regarding the 2003 revenue requirements application for the Western system.

Even with these accomplishments, financial results were disappointing. These results are mainly attributable to residential and commercial gas deliveries that were, despite slightly colder than normal weather, lower than what was forecast when the Company's regulator established rates.

Dampening of commodity price volatility in 2002

Natural gas commodity prices in 2002 were about 30 percent lower than in 2001. This reduction, together with the optimistic forecast of deliveries to residential and commercial customers, resulted in the Company having the lowest retail residential and commercial rates in British Columbia in 2002, with the exception of retail rates in Fort Nelson.

Over the past several years the average quantity of natural gas consumed by each residential and small commercial customer has declined. This decline is due to a number of factors, including: the replacement of older heating equipment with newer, more efficient systems; energy conservation; use of alternative fuels such as electricity and wood; and the lingering effect of the high natural gas prices experienced two years ago.

Unfortunately, natural gas commodity prices in early 2003 have increased significantly. Current forecasts indicate 2003 prices will be approximately 85 percent higher than the average gas commodity price paid by the Company in 2002.

Improved Financial Position and Flexibility

In December 2002, the Company completed a $15-million long-term financing to allow for the payment of a $2.75 per share special dividend to common shareholders in January 2003 and to provide for new working capital. This financing also improved the Company's capitalization for regulatory purposes by more closely aligning actual common equity with that allowed by the regulator.

In early 2003, the Company entered into an agreement with a new operating lender to provide a $25-million line of credit in support

of working capital and commodity hedging activities. This new line of credit provides the Company with additional financial flexibility related to day-to-day operations, including the ability to more appropriately manage gas commodity price risk.

Customers

Methanex

The Company is pleased with the new long-term contract negotiated with Methanex. The new contract, with a term of November 1, 2002 through October 31, 2009, replaces three contracts that were to expire in 2002, 2003 and 2009. It provides for a significant increase in the firm volume commitment by Methanex at a substantially reduced firm transportation toll.

The new Methanex contract provides for fixed monthly demand charges irrespective of whether the methanol plant operates. Approximately 62 percent of the Company's annual deliveries are made to Methanex and, under the new agreement, Methanex will account for approximately 25 percent of the Company's 2003 operating margin.

Skeena

The pulp mill on Watson Island located near Prince Rupert, formerly owned by Skeena Cellulose Inc., shut down in 2001 and sought protection from its creditors later that year. During the bankruptcy proceedings, Skeena terminated its contract with Pacific Northern Gas. In mid-2002 Skeena was acquired by North West British Columbia Timber & Pulp Ltd. ("NWBC Timber"). NWBC Timber has advised us that the Watson Island pulp mill will recommence operations in mid-2003.

Other

The continuing weak economy in the west-central service area and the ongoing softwood lumber trade dispute had a negative impact on the Company's 2002 financial performance. Notwithstanding these factors, the lumber mills and dry kilns in the west-central area (other than the facilities owned by Skeena) operated at high capacity levels throughout most of 2002. This was mainly due to increased annual allowable cuts on wood infested by the mountain pine beetle and lower than average softwood lumber tariffs levied on many area operators.

The weak economy also had a negative impact on the total number of residential and commercial customers, as well as the level of gas consumption per account. In 2002, the average number of residential and commercial customers connected and taking gas from the system remained virtually unchanged from levels in 2001.

Furthermore, the Company experienced two line breaks in 2002 and one in January 2003. In June 2002, a major landslide 30 kilometres east of Terrace ruptured the transmission mainline, however temporary repairs were completed within four days. In November 2002, a line failure occurred on a looped section of the 10-inch mainline west of Burns Lake and was repaired within 24 hours. In January 2003, a rockslide caused a failure of the 8-inch line between Terrace and Prince Rupert and was repaired within 24 hours. None of these line breaks resulted in disruption of service to residential and small commercial customers. We are extremely proud of the performance of the Pacific Northern Gas employees who handled these line breaks in a safe, professional, and timely manner.

Outlook

We anticipate the convenience and environmental benefits of natural gas over other forms of energy will keep demand steady. Natural gas is cleaner burning than other fossil fuels, generating the least amount of carbon dioxide per unit of energy produced. We in the industry believe that natural gas is part of the solution to reducing greenhouse gas emissions. Following Canada's ratification of the Kyoto Accord, there continues to be considerable debate on how this might unfold going forward; this said, the final

outcome should not materially affect the operations of Pacific Northern Gas.

The British Columbia Provincial Government also released its new energy plan in November 2002. While it focuses primarily on the electric power sector, it states that energy reliability will be maintained and improved through well-functioning natural gas markets and coordinated electricity planning. This is positive for our industry going forward.

The moratorium on oil and gas exploration off the Pacific Coast continues to be in effect; however, the provincial government's energy plan notes that a "dedicated provincial offshore oil and gas team will develop a provincial position, work with the federal government and move effectively toward development of the offshore oil and gas resources." This team is being led by the former Deputy Minister of Energy and Mines who was recently appointed Deputy Minister Responsible for the British Columbia Offshore Oil and Gas Team. We are working with the provincial government and First Nations to ensure Pacific Northern Gas will be participating in these encouraging developments.

Reference was made in last year's report to shareholders of our efforts in promoting a gas-fired power generation unit in the Kitimat/Terrace area. These efforts were discontinued following the significant changes in the merchant power market in late 2001 and early 2002; however, this analysis was completed and will be reserved for possible future use.

In late 2002, the Company filed revenue requirements applications with the British Columbia Utilities Commission, the regulatory agency that approves the tolls, terms and general conditions under which the Company provides service to its customers. The applications sought the Commission's approval of rates for 2003 and requested approval of a new deferral account in all divisions of the Company to record variances between projected and actual gas consumption by residential and small commercial customers. The objective of the deferral account is to manage the forecast risk associated with weather and other factors affecting gas consumption. If actual gas use per customer account varies from the forecast average use per account set forth in the applications, the financial impact of the difference will be deferred for future recovery or refund to the customer.

In early 2003, the Company successfully negotiated a settlement of the Western system 2003 revenue requirements application with its customers. Commission staff facilitated the negotiations and the settlement included agreement on the implementation of the residential and small commercial customer gas deliveries deferral account.

Thanks and Farewell

Two directors, Eric L. Schwitzer and Robert T.F. Reid, left the board in the last twelve months. Mr. Schwitzer served on the Board since 1999 and Mr. Reid since 2001. I thank them both for their service and wish them every success in their future endeavours. I would also like to welcome David G. Unruh, Senior Vice President and General Counsel of Duke Energy Gas Transmission, who joined the Board of Directors in March 2002. David served as the Company's Secretary from 1993 to 2002.

In closing, I would like to thank our shareholders for their continuing support and our employees for their perseverance and outstanding commitment to Pacific Northern Gas.

R.G. Dyce

ROY G. DYCE
PRESIDENT AND CHIEF EXECUTIVE OFFICER

MARCH 11, 2003

The Toronto Stock Exchange ("TSX") requires that the Company disclose annually the corporate governance practices of its Board of Directors ("Board"). Through its Corporate Governance Committee, the Board administers a program to develop and sustain suitable and effective processes and structures to guide the direction and management of the business and affairs of the Company in the pursuit of enhanced corporate performance and shareholder value. The following report addresses how the Company fulfills the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSX.

Board of Directors: The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management in carrying out its responsibility for the day-to-day operations of the business. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Company meets its obligations on an ongoing basis in a reliable and safe manner. The Board ensures that long-term goals and a strategic planning process are in place for the Company, and that systems have been developed to monitor and manage the principal risks and potential returns associated with the business activities.

The Board acts independently of management either directly or through committees of the Board which are delegated some of the Board's responsibilities. The Chair of the Board is an unrelated director. At each meeting of the directors, the outside directors meet in-camera without members of management present. Terms of reference for the Board and position descriptions for the Chairman and the President and Chief Executive Officer have been approved by the Board.

The Board is composed of seven directors. There is currently one vacancy on the Board. One of the directors is a full-time officer of the Company, one is currently a full-time officer of Westcoast Energy Inc. ("Westcoast") which owns 100 percent of the voting common shares and is therefore considered a significant shareholder, and one retired in 1999 as the President and Chief Operating Officer of Westcoast and provided consulting services to Westcoast until 2002. The remaining three directors do not have interests in or relationships with the Company (other than interests and relationships arising from shareholdings), which could, or could reasonably be perceived to materially interfere with such directors' ability to act with a view to the best interests of the Company. The Board has concluded that a majority of the directors of the Company are unrelated and that the composition of the Board fairly reflects the interests of shareholders other than the significant shareholder.

The Corporate Governance Committee, which has primary responsibility for the search for and recommendation of new candidates for election to the Board, seeks to select well-qualified candidates with a diversity of background, experience and geographic location to maintain a well-balanced and highly competent group of directors with the ability to act together effectively. Through the auspices of the Corporate Governance Committee, a formal assessment of the overall effectiveness of the Board is conducted annually.

Committees of the Board: The Board has established and adopted terms of reference for each of the Audit, Executive, Environment, Health and Safety, Compensation, and Corporate Governance Committees.

The *Audit Committee* is composed entirely of unrelated directors. One of the members is a financial professional and all members are financially literate. One of the three committee members is a full-time officer of Westcoast. This committee is responsible for ensuring that the

Company's management has designed and implemented an effective system of internal financial controls, for reviewing and reporting on the integrity of the consolidated financial statements of the Company, for ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts and for reviewing the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management. At each meeting of the Audit Committee, members of the committee meet in-camera with the external auditors without management present.

The *Executive Committee* is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and Chief Executive Officer and to perform such functions and exercise such powers as are specifically delegated to the committee by the Board. It is composed of three directors, one of whom is a full-time officer of the Company. The Board has determined that a majority of the committee members are unrelated.

The *Environment, Health and Safety Committee* is composed of three directors, one of whom is a full-time officer of the Company. A majority of the committee members are unrelated. This committee is responsible for reviewing and monitoring the policies and activities of the Company relating to environment, health and safety matters on behalf of the Board.

The *Compensation Committee* is composed entirely of directors who are unrelated. One of the three members is a full-time officer of Westcoast. This committee is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. In addition, it is responsible for periodically reviewing the adequacy and form of compensation of directors and for ensuring that the compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly.

The *Corporate Governance Committee* is composed entirely of unrelated directors. This committee's prime responsibility is to develop and monitor the Company's overall approach to corporate governance issues and to administer a corporate governance system which is effective in the discharge of the Company's obligations to its shareholders. Through the Corporate Governance Committee the Board develops sound corporate governance practices to enhance corporate performance. This committee also has the responsibility for proposing new members to the Board, establishing criteria for Board membership, recommending composition of the Board and its committees, assessing directors' and Board performance on an ongoing basis and ensuring an orientation and education program is in place for new members of the Board.

Special Committees of the Board of Directors are struck from time to time to deal with matters of significance before the Company.

Shareholder Feedback and Concerns: The Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response from an appropriate officer of the Com-

pany. The Company has adopted a disclosure policy which establishes procedures to provide the public with broad disclosure on a timely basis of material information concerning the affairs of the Company. The Company's practices encourage the free flow of accurate and appropriate communication and, at the same time, discourage selective disclosure of material information that has not been publicly disclosed.

Decisions Requiring Board Approval: The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain of its authorities to management and by reserving certain powers to itself. In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, nominating candidates for election to the Board, constituting committees of the Board and determining director compensation.

Role of Management: Members of the management team report to the Board and its committees on a regular basis to review the Company's financial and operational results and the Company's progress in fulfilling its strategic goals and objectives. The Board develops processes for defining its expectations of management, such as reviews of the Company's strategic plan with management and a comprehensive review of the performance of the President and Chief Executive Officer which is carried out by the Compensation Committee.

2002 Financial Performance

Pacific Northern Gas Ltd.'s financial performance in 2002 was below management and market expectations. A major factor affecting 2002 results was that actual deliveries to residential and commercial customers for the year ended December 31, 2002 were 0.8 petajoules below levels used for ratemaking purposes. This shortfall in deliveries reduced operating margins by $3.0 million and reduced net income by $1.9 million for the year ended December 31, 2002. As a result, Pacific Northern Gas Ltd. reported a decrease in net income for the year ended

SELECTED FINANCIAL HIGHLIGHTS (Dollar amounts in thousands except per share and per GJ figures)	2002	2001
Deliveries (TJ) – Sales	8 045	7 768
– Transportation service	31 418	24 013
– Total	39 463	31 781
Customers at year end	39,254	39,230
Weighted average cost of gas purchased ($ per GJ)	$ 4.11	$ 6.18
Income before income taxes	$ 11,525	$ 11,684
Net income	$ 4,590	$ 5,715
Operating cash flow	$ 14,570	$ 15,843
EBITDA[1]	$ 28,820	$ 31,062
Earnings per common share	$ 1.20	$ 1.52

[1] Net income before interest expense, investment and other income, income taxes, depreciation, and amortization of deferred charges.

SELECTED CONSOLIDATED QUARTERLY RESULTS (UNAUDITED)

2002 (Dollar amounts in thousands except for per share data)	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating Revenues	$ 36,090	$ 23,370	$ 16,714	$ 32,889	$ 109,063
Net income (loss)	3,316	893	(889)	1,270	4,590
Earnings (loss) per common share – basic	0.91	0.23	(0.28)	0.34	1.20
Earnings (loss) per common share – diluted	0.90	0.22	(0.28)	0.34	1.18

2001 (Dollar amounts in thousands except for per share data)	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating Revenues	$ 54,880	$ 29,811	$ 22,950	$ 30,954	$ 138,595
Net income	2,713	1,213	159	1,630	5,715
Earnings per common share – basic	0.74	0.32	0.02	0.44	1.52
Earnings per common share – diluted	0.74	0.32	0.02	0.43	1.51

December 31, 2002. Net income in 2002 was $4.6 million, compared with $5.7 million in 2001. After providing for preferred share dividends, earnings per common share were $1.20, compared with $1.52 in the previous year.

FOURTH QUARTER RESULTS

The Company's operating results for the fourth quarter of 2002 were adversely affected by weather that was approximately ten percent warmer than normal. The warmer weather reduced deliveries to residential and commercial customers by 0.2 petajoules in the fourth quarter of 2002, resulting in a reduction of net income by approximately $0.3 million. Weather in the fourth quarter of 2001 was approximately three percent colder than normal.

In addition to the impact of warmer than normal weather in the fourth quarter of 2002, actual deliveries to residential and commercial customers were 0.3 petajoules lower than the volumes used by the Company's regulator in setting rates. This resulted in a reduction in net income of approximately $0.7 million.

OPERATING INCOME

Income before income taxes for 2002 was $11.5 million compared to $11.7 million in the preceding year. The components of the decline of $0.2 million are described in the table below.

Operating, maintenance, administrative and general expenses totalled $19.2 million, a decrease of $1.0 million relative to 2001. The lower expenses reflect a reduction in company use gas expense of approximately $0.6 million, caused by lower commodity prices offset by higher volumes of company use gas consumed. In addition, overhead expenses capitalized to plant, property and equipment increased by $0.4 million over the prior year, due to higher levels of capital additions.

COMPARISON OF INCOME BEFORE INCOME TAXES
(Dollar amounts in thousands)

	2002 vs. 2001
Lower residential and commercial customer deliveries, compared to levels used in setting rates	$ (462)
Lower allowed return on equity	(321)
Lower operating, maintenance, administrative and general expenses, excluding company use gas	137
Higher capitalization of overhead expenses to plant, property and equipment	361
Other	126
Decrease in income before income taxes	$ (159)

Natural Gas Deliveries

Natural gas deliveries totaled 39.5 petajoules* compared with 31.8 petajoules in 2001. A comparison of 2002 deliveries and 2001 deliveries is provided in the adjacent table:

*The joule is a metric energy measurement unit, one gigajoule (GJ) is equivalent to 0.94782 million British thermal units. One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic metres is equivalent to 35.301 thousand cubic feet.

DELIVERIES IN TERAJOULES	2002	2001	Percent Increase
Customer			
Residential	**3 503**	3 470	1.0
Commercial	**2 967**	2 936	1.1
Small Industrial	**3 805**	3 592	5.9
Large Industrial	**29 188**	21 783	34.0
Total	**39 463**	31 781	24.2

Deliveries to large industrial customers increased substantially from 2001 to 2002 because Methanex Corporation, the Company's largest customer, operated for twelve months in 2002 and only six months in 2001. Deliveries to Methanex were 11.2 petajoules higher in 2002 than in 2001. However, revenue recorded on Methanex deliveries increased by only 3.3 percent, primarily due to the delivery of non-revenue bearing deficiency volumes in 2002.

While deliveries to residential and commercial customers increased slightly in 2002 over the prior year, actual deliveries were 0.8 petajoules lower than the volumes used in setting rates, resulting in an under-recovery of the regulated cost of service of $3.0 million, before income taxes.

Deliveries to small industrial customers increased by 5.9 percent over the prior year, primarily due to the operation of inland lumber mills at high capacity levels in reaction to increased annual allowable cuts on wood infested by the mountain pine beetle and lower than average softwood lumber tariffs levied on many area operators.

Customer Additions

In 2002, 270 new customers were connected to the Company's distribution systems, compared with 237 in 2001. This increase in customer additions is the result of a continued strong economic activity in the northeastern service area. Although 270 new customers were connected to the distribution system in 2002, the Company experienced a net gain of only 24 customers. This is a result of 246 customers leaving the distribution system, primarily in the Company's west-central service area.

In mid-2001 Pacific Northern implemented a modified main extension and service connection policy. These changes require new customers to fully cover the cost of service line connections to the distribution system. Also, in situations where main extensions are required, initial customers must fund the full amount of any shortfall between the Company's allowable investment and total estimated construction costs. This has eliminated the Company's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited remaining opportunity to extend gas mains into unserviced rural areas in the west-central service area.

Natural Gas Supply

Natural gas is purchased at prevailing market prices and passed through to customers without any mark-up by the Company. Variances in gas purchase prices from those included in current retail rates are deferred for subsequent refund to or recovery from customers.

A gas supply price risk management plan is used to manage gas supply price volatility through hedging arrangements and fixed price gas supply contracts. For 2002, approximately 20 percent of gas purchases were hedged. Note 14 to the Consolidated Financial Statements provides further information as of December 31, 2002 with regard to 2003 gas supply.

Virtually all of the Company's gas supply is comprised of the pooled gas stream available from the Duke Energy (formerly Westcoast Energy) transmission pipeline system. This includes all of the supply to the Company's transmission line serving its west-central service area and approximately 75 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from Duke Energy, the Fort St. John system incorporates two supply interconnections with Williams Energy (Canada) Inc.'s West Stoddart Pipeline. In Dawson Creek approximately 24 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects Pacific Northern's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long-term contract with CanWest Gas Supply Inc. accounted for about 68 percent of total 2002 purchases. Other supplies included purchases under seasonal and spot arrangements.

Large Industrial Customers

The Company has firm transportation service and interruptible sales agreements with three of its large industrial customers: Methanex Corporation ("Methanex"), Eurocan Pulp & Paper Co. ("Eurocan") and Alcan Inc., Primary Metal Group (B.C.) ("Alcan"). In addition, the Company had a firm transportation service and interruptible sales agreement with Skeena Cellulose Inc. ("Skeena"), which was terminated on April 23, 2002 while Skeena was under protection from its creditors under the Companies' Creditors Arrangement Act.

The large industrial customers produce commodities that are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operation during sustained periods of low prices for their commodities.

The Company delivers gas to its other large industrial customer, British Columbia Hydro and Power Authority ("BC Hydro"), under an interruptible sales agreement for electric power generation at BC Hydro's facility in Prince Rupert.

Deliveries to Methanex in 2002 accounted for approximately 65 percent of volumes delivered by the Company and approximately 19 percent of the Company's operating revenues. Transportation service to Methanex was made pursuant to three agreements that were to expire between 2002 and 2009. On August 29, 2002 the Company entered into a new seven-year take-or-pay contract with Methanex, commencing November 1, 2002, which replaced the three pre-existing contracts. An annual demand charge based on a firm toll of 50 cents per gigajoule will apply over the term of the new agreement. In addition, under the new contract Methanex will supply a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. This compares to the rate in effect at October 31, 2002 of 73 cents per gigajoule, taking into account deficiency volumes, but excluding company use gas costs. The contract also includes

a profit-sharing mechanism during periods of high methanol prices and relatively low natural gas prices. The contract was approved by the British Columbia Utilities Commission (the "Commission") in a decision dated July 31, 2002 and was accepted for filing on September 17, 2002.

The sale of Skeena to North West British Columbia Timber & Pulp Ltd. ("NWBC Timber") was completed on April 30, 2002. The Company has been advised by NWBC Timber that the pulp mill will be recommencing operations in 2003. The reopening of the Skeena facilities is dependent upon a number of factors, including the market prices for pulp and wood products. All amounts owing to the Company by Skeena at December 31, 2002, totaling $2.5 million, have been provided for in the Company's allowance for doubtful accounts.

The long-term transportation service and sales contracts with Eurocan and Alcan are in effect through October 31, 2004. During 2002, deliveries to Eurocan and Alcan accounted for 9 percent of the Company's total gas deliveries and 6 percent of operating revenues.

Regulatory Activities

In November 2001, the Company filed revenue requirements applications with the Commission for approval of new rates to be effective January 1, 2002 for all service areas.

The applications for 2002 were considered by the Commission through an oral public hearing process for the Western system and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions of Pacific Northern Gas (N.E.) Ltd.

The Commission's decisions on the Company's 2002 revenue requirements applications, issued on July 31, 2002, denied the Company's requests for an increase in the equity risk premium from 75 to 100 basis points as well as an increase in the deemed common equity component of the capital structure from 36 percent to 45 percent for the Western system. In addition, the Commission disallowed certain operating expenses and deferral accounts and increased projected gas deliveries to residential, commercial and industrial customers by 0.7 petajoules. On August 22, 2002, the Company filed an application with the Commission for reconsideration and variance of the July 31, 2002 decisions. On October 30, 2002, the Commission issued decisions denying the Company's requests.

The 2002 allowed rate of return on common equity was 9.88 percent for the Western system and Tumbler Ridge division, and 9.63 percent for the Fort St. John/Dawson Creek division, based on a deemed common equity component of rate base of 36 percent. The allowed rate of return on common equity includes a 75 basis point premium over the low risk benchmark utility rate of return (50 basis point premium for the Fort St. John/Dawson Creek division).

WESTERN SYSTEM

For 2002, the Commission continued its direction to defer the difference between actual sales to Methanex, Skeena, Eurocan and B.C. Hydro and the forecast sales used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). The availability of the ICDDA increased 2002 operating income by $0.2 million. The Commission also accepted the Company's forecast of gas supply costs for 2002. Rate riders were approved for the period April 1, 2002 to March 31, 2003 to refund a credit balance accumulated in the gas purchase variance payable account. In 2002, the reduction in customer revenue from credit rate riders totalled $2.4 million, and was applied, on an after tax basis, to reduce the gas purchase variance payable account.

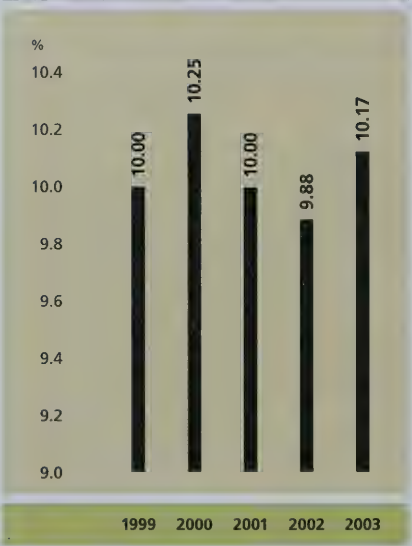
The 2003 revenue requirements application for the Western system was filed with the Commission at the end of November 2002. The application reflects increases to both the delivery charges and the gas supply commodity charges. The 2003 forecast gas supply commodity charges

were approximately 21 percent higher than what was embedded in rates effective December 31, 2002. The Commission accepted the Company's gas supply price forecast and increased the gas supply commodity cost component of rates accordingly, effective January 1, 2003.

In the revenue requirements application, residential and commercial deliveries in 2003 in the Western system are forecast to increase by approximately 4 percent compared to 2002 actual volumes. The deliveries to small industrial customers are projected to be lower in 2003 by approximately 10 percent, due to ongoing economic difficulties experienced by forestry companies in the service area. The 2003 application assumes that the Skeena pulp mill will operate for six months in 2003.

In December 2002, the Commission confirmed that its formula for determining the allowable return on common equity in 2003 resulted in a 9.42 percent return for a low risk benchmark utility for the year. For Pacific Northern, a return on equity risk premium of 75 basis points applies to the Western system resulting in an allowable return on common equity of 10.17 percent for 2003. The Commission approved interim rates effective January 1, 2003 based on a 36 percent deemed common equity component of the capital structure.

PNG WEST ALLOWED RETURN ON COMMON EQUITY 1998-2002



On February 13, 2003 the 2003 revenue requirements application for the Western system was successfully negotiated with PNG's customers under the supervision of Commission staff. Key to the settlement was reaching agreement on the implementation of a deferral account to record the variance between actual deliveries to the residential and small commercial customer classes and budgeted deliveries during 2003. The Commission approved the terms of the negotiated settlement in early March 2003.

FORT ST. JOHN/DAWSON CREEK DIVISION

The Commission accepted the Company's forecast of gas supply costs for 2002. Rate riders were approved for 2002 to recover debit balances recorded in the gas purchase variance recoverable account at December 31, 2001 over a period of three years. In 2002, customer revenue from rate riders totalled $1.1 million, which was applied, on an after tax basis, to reduce the gas purchase variance recoverable account.

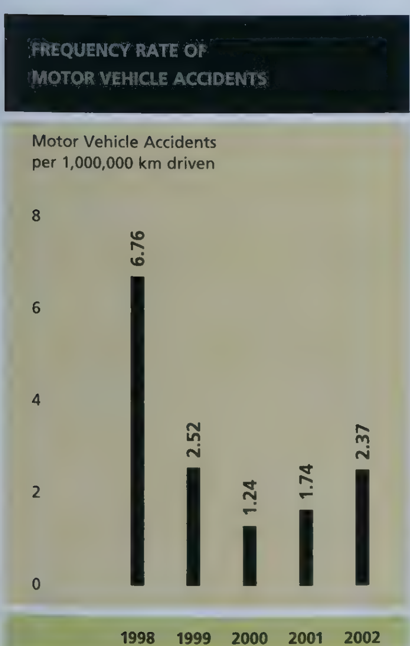
The Fort St. John/Dawson Creek 2003 revenue requirements application, filed in November 2002, seeks Commission approval to increase the gas delivery charge component of its natural gas rates. The Commission approved interim rates based on deemed common equity of 36 percent, and an allowable return on common equity of 9.92 percent for 2003, on an interim basis. The interim rates effective January 1, 2003, resulted in rate increases of between 17 and 19 percent for residential and small commercial customers, respectively.

TUMBLER RIDGE DIVISION

The Tumbler Ridge 2003 revenue requirement application was filed with the Commission at the end of November 2002. The application seeks Commission approval to increase the gas delivery charge component of natural gas rates. The Commission approved interim rates, effective

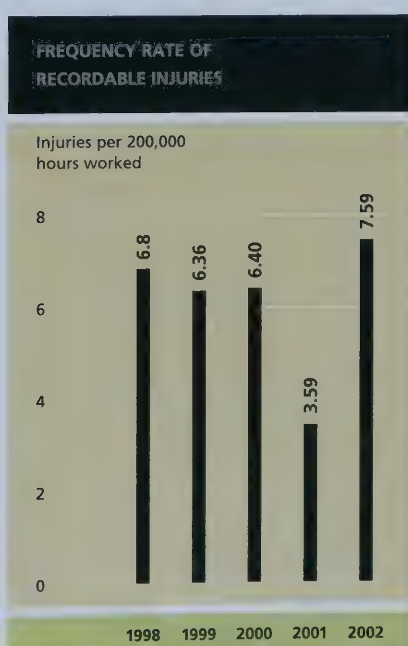
January 1, 2003, resulting in rate increases of approximately 24 percent for residential and small commercial customers.

The Commission is conducting a written hearing process in respect of the Fort St. John/Dawson Creek and Tumbler Ridge divisions. The Commission is expected to render a decision on the application in the second quarter of 2003.



Environmental, Health & Safety

Transmission pipelines are constructed with pressure tested steel and covered with a protective coating to prevent corrosion. The west-central mainline system and key supply points for the northeast system have preventative alarms, which are monitored by Duke Energy's Control Centre. The Company conducts regular aerial and land surveillance of the pipeline to check for corrosion, leaks, vegetation and right-of-way encroachment.



The Company strives to achieve safe performance of all work activities and was awarded the Canadian Gas Association's 2001 Safety Award for the best overall safety performance of any Canadian gas utility in the distribution category. While the frequency of motor vehicle accidents in 2002 increased over 2001 levels, it represents an improvement of 23 percent compared to the average accident rate for the previous four years. The frequency of recordable injuries increased by 31 percent in 2002 compared to the average for the previous four years.

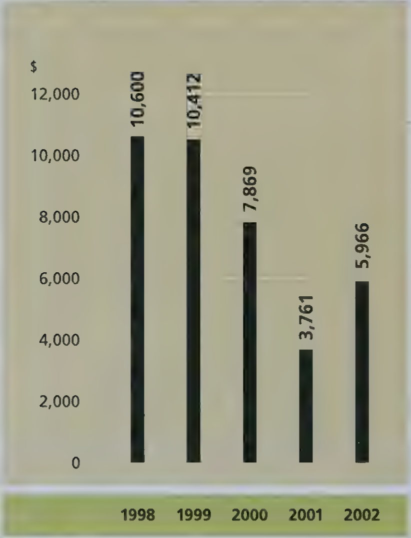
Engineering and Operations

The Company continued its ongoing stress corrosion cracking investigations and repairs during the year. A number of sections of pipe were excavated and repaired downstream of the compressor stations at Vanderhoof and Burns Lake.

Installation of a programmable logic controller-based system at the Summit Lake Compression Station was completed in 2002. The new system offers more reliable control and a greater level of operational flexibility, while allowing for remote control and troubleshooting of the compressor units.

During 2002, the Company increased capital spending by 59 percent compared to 2001 levels. Expenditures remained 23 percent below the

CAPITAL EXPENDITURES 1998-2002
(Dollar amounts in thousands)



CAPITAL EXPENDITURES (Dollar amounts in thousands)	2002	2001
Transmission System	$ 2,891	$ 1,298
Distribution System	2,109	2,088
Processing Plant	41	85
Other	925	290
Total	$ 5,966	$ 3,761

average levels of capital expenditures for the last five years. Capital expenditures in 2002 totalled approximately $6 million, and this level is forecast to continue for the next three years.

COPPER RIVER SLIDE

On June 8, 2002, a slide east of Terrace ruptured a section of the mainline. Service to residential and most commercial customers was not interrupted, however, service to large industrial customers in Kitimat had to be curtailed. Installation of temporary lines was completed less than a week after the line break, restoring service to all customers. Permanent repairs were completed in December 2002. The cost of the temporary repairs, totaling $0.2 million net of income taxes, was deferred as line break expense and will be amortized into rates over ten years, commencing in 2003. The cost of the permanent repair was $2.7 million and has been included, net of insurance recoveries, in capital expenditures for 2002. Uninsured business interruption losses resulting from the pipeline break were estimated to be $0.4 million for the large industrial customers, and have been recorded in the Industrial Customers Deliveries Deferral Account, net of income taxes.

Liquidity and Capital Resources

At December 31, 2002, the Company had a secured demand line of credit in the amount of $20 million that provided funds for general corporate and working capital requirements. The amount available under this facility was subject to borrowing base requirements. As a result of seasonality in operations, marginable receivables and other assets are significantly reduced in the second and third quarters compared to the winter heating season, thus constraining availability of the demand line of credit. At December 31, 2002, the amount available under the facility was approximately $8.7 million, none of which had been drawn.

The Company purchases gas for resale to its core market customers, and passes through the commodity cost of gas to those customers without markup. The rates charged to core market customers are based in part on projected gas supply prices. The Company's liquidity requirements are affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases.

Reductions in capital expenditures compared to historical levels, combined with accelerated recoveries of regulatory deferrals, ongoing cost savings realized from the corporate reorganization in 2000, new long-term debt and the suspension of common dividends from July 2000 to December 2002, have allowed the Company to reduce its draw on the demand line of credit.

In February 2003, the Company negotiated a new secured demand line of credit in the amount of $25 million to replace the existing line of credit. The new line will provide funds for general corporate and working capital requirements, as well as provide support for the Company's planned commodity hedging activities.

Long-term debt repayments in 2002 amounted to $2.6 million. New long-term financing in the amount of $15 million was issued in December 2002 and used for general corporate purposes and the payment of dividends. The loan will be repaid over a term of ten years, and bears interest at a floating rate. A special dividend of $2.75 per common share was declared on December 12, 2002 and paid on January 23, 2003. The special dividend represented a payment to the common shareholders of approximately $10 million, and results in a capital structure that is more closely aligned with that approved by the Commission.

Commitments for capital expenditures in 2003 are minimal. Planned capital spending is primarily directed toward distribution mains and services and is forecast to be approximately $6.5 million in 2003.

Dominion Bond Rating Service rates the Company's capital instruments as follows at December 31, 2002:

Debentures	BB (high)
Preferred Shares	Pfd-4 (high)

Risk Management

OPERATING RISK

In 2002, 74 percent of energy deliveries were made to the Company's four largest industrial customers, compared to 69 percent in 2001. Two of these customers, totaling approximately 9 percent of annual deliveries, have firm gas transportation agreements expiring over the next two years. In addition, the Company's new contract with Methanex expires in 2009. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be harmed by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources.

The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated. In addition, Pacific Northern's service area is dependent upon industrial customers, many of which are tied to the forest sector, for its economic stability. A prolonged decline in the forest and other related sectors could negatively impact deliveries to all customer classes.

The average cost of natural gas has increased substantially over the last six months, therefore the prospect of fuel-switching by customers poses a risk, as other energy sources remain cost competitive.

FINANCIAL RISK

Fluctuations in the price of natural gas could increase the working capital financing requirements and related costs for accounts receivable, and high customer rates may give rise to higher bad debt costs.

The recovery of the Company's accumulated deferral accounts has an impact on the Company's liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval.

The Company's investment activities are financed by cash generated from operations and drawings under its operating line together with proceeds from the issue of long-term debt and share capital.

The Company maintains insurance against exposures to the physical loss of its pipeline, compressor and other above ground facilities, as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past experience, the deductibles have increased over time and, depending on the number and severity of future outages, the financial impact on the Company could be material.

Outlook

Pacific Northern's 2003 revenue requirement applications filed with the Commission in late 2002 address a number of issues. These include the continuing difficulty in accurately forecasting core market consumption levels, and the uncertainty regarding whether the Skeena Cellulose pulp mill will restart operations, and if so, at what level.

As a result of the difficulty in accurately forecasting deliveries to residential and commercial customers in 2001 and 2002, the Company requested the Commission to approve a residential/small commercial customer deliveries deferral account commencing in 2003. The settlement negotiated with the Western system customers in February 2003 established such a deferral account.

The applications to the Commission project deliveries in 2003 to residential and commercial customers will be approximately 4 percent greater than experienced in 2002. Achieving the higher delivery forecast will be dependent on a number of factors, including the volatility and absolute level of gas prices and the relative prices of competitive fuels. The outlook for natural gas prices over the next year (forward gas price strip as at February 25, 2003, for a 12-month price) is approximately 85 percent higher than the weighted average cost of gas purchased by the Company during 2002.

The 2003 rate applications to the Commission assume the Skeena pulp mill will operate for six months during 2003. The applications are also premised on virtually no recovery in general economic conditions during 2003 throughout the Company's service area.

The Company develops a gas supply price risk management plan each year to manage gas supply price volatility through hedging arrangements and fixed price gas supply contracts. Approximately 20 percent of gas purchases in 2002 were covered under fixed price contracts or call options. The Company expects to either hedge or enter into fixed price contracts for a substantial portion of its 2003 gas requirements following completion of the 2003/2004 gas supply price risk management plan.

CONSOLIDATED FINANCIAL STATEMENTS

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of directors who are not employees of the Company or of its subsidiary. The Audit Committee meets regularly with management, the internal auditors, and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee reports its findings to the Board of Directors.

Deloitte & Touche LLP performed an independent audit of the consolidated financial statements for the year ended December 31, 2002. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report. The financial statements for the year ended December 31, 2001 were audited by Ernst & Young LLP.

January 22, 2003

ROY G. DYCE
PRESIDENT AND CHIEF EXECUTIVE OFFICER

E.A. FLETCHER
TREASURER AND COMPTROLLER

To the Shareholders of
Pacific Northern Gas Ltd.

We have audited the consolidated balance sheet of Pacific Northern Gas Ltd. as at December 31, 2002 and the consolidated statement of income, retained earnings and cash flow for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and the results of its operations and its cash flow for the year then ended in accordance with Canadian generally accepted accounting principles. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a basis consistent with that of the preceding year, except for the changes in accounting policies described in note 1 to the consolidated financial statements.

The financial statements as at December 31, 2001 and for the year then ended were audited by other auditors who expressed an opinion without reservation on those statements in their report dated January 28, 2002.

Deloitte & Touche LLP

CHARTERED ACCOUNTANTS
VANCOUVER, CANADA,
JANUARY 22, 2003

As at December 31 (Dollar amounts in thousands)	2002	2001
ASSETS [notes 7 and 8]		
Current assets		
Cash and short term investments	$ 10,027	$ 117
Accounts receivable [notes 2 and 12]	21,236	21,629
Inventories of supplies and natural gas	1,365	1,520
Prepaid expenses	200	780
	32,828	24,046
Plant, property and equipment [note 3]	177,314	179,301
Deferred charges		
Debt expense	982	797
Gas purchase variance recoverable	–	199
Pipeline rehabilitation costs	575	503
Other	807	2,267
	2,364	3,766
	$ 212,506	$ 207,113

See accompanying notes

On behalf of the Board:

ROY G. DYCE
DIRECTOR

ROBERT F. CHASE
DIRECTOR

As at December 31 (Dollar amounts in thousands)	2002	2001
LIABILITIES		
Current liabilities		
Bank indebtedness [note 7]	$ –	$ 8,675
Accounts payable and accrued liabilities [note 12]	23,961	11,036
Gas purchase variance payable	2,678	–
Income and other taxes payable	1,845	10,668
Long term debt due within one year [note 8]	4,379	2,650
	32,863	33,029
Long term debt [note 8]	90,224	79,539
Deferred income taxes [note 4]	15,453	15,200
	138,540	127,768
Commitments and contingency [note 14]		
SHAREHOLDERS' EQUITY		
Preferred shares [note 9]	5,000	5,000
Common shares [notes 10 and 11]	8,948	8,869
Contributed surplus [note 10]	2,299	2,158
Retained earnings	57,719	63,318
	68,966	74,345
	73,966	79,345
	$ 212,506	$ 207,113

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31 (Dollar amounts in thousands, except for per share data)	2002	2001
Operating revenues [notes 2 and 12]	$ 109,063	$ 138,595
Cost of sales [note 12]	56,820	83,344
	52,243	55,251
Operating and maintenance	13,885	14,834
Administrative and general	5,279	5,385
Amortization of deferred charges	1,700	2,770
Municipal and other taxes	4,259	3,970
Depreciation	7,953	7,811
	33,076	34,770
	19,167	20,481
Investment and other income	50	136
	19,217	20,617
Income deductions		
Interest on long term debt	6,868	7,671
Other	824	1,262
	7,692	8,933
Income before income taxes	11,525	11,684
Income taxes [note 4] – current	7,225	10,830
– deferred	(290)	(4,861)
	6,935	5,969
Net income for the year	$ 4,590	$ 5,715
For common shares		
Net income for the year	$ 4,590	$ 5,715
Provision for dividends on preferred shares	337	338
Net income applicable to common shares, basic and diluted	$ 4,253	$ 5,377
Earnings per common share [note 6]		
Basic	$ 1.20	$ 1.52
Diluted	$ 1.18	$ 1.51

See accompanying notes

Years ended December 31 (Dollar amounts in thousands)	2002	2001
Balance, beginning of year	**$ 63,318**	$ 57,941
Net income for the year	**4,590**	5,715
	67,908	63,656
Preferred share dividends	**337**	338
Common share dividends	**9,852**	–
	10,189	338
Balance, end of year	**$ 57,719**	$ 63,318

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31 (Dollar amounts in thousands)	2002	2001
OPERATING ACTIVITIES		
Net income for the year	$ 4,590	$ 5,715
Add (deduct) items not involving cash:		
Deferred income taxes	(290)	(4,861)
Depreciation and amortization	9,727	10,581
Other	543	4,408
Operating cash flow	14,570	15,843
Non-cash working capital changes [note 15]	(1,776)	5,070
Net cash provided by operating activities	12,794	20,913
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(5,965)	(3,761)
Decrease (increase) in deferred charges	(372)	1,345
Net cash (used by) investing activities	(6,337)	(2,416)
FINANCING ACTIVITIES		
Decrease in bank indebtedness	(8,675)	(16,132)
Issue of long-term debt	15,037	12,031
Repayment of long-term debt	(2,623)	(15,326)
Issue of common shares [note 10]	220	–
Dividends paid	(506)	(338)
Net cash provided by (used by) financing activities	3,453	(19,765)
Increase (decrease) in cash and short-term investments during the year	9,910	(1,268)
Cash and short-term investments, beginning of year	117	1,385
Cash and short-term investments, end of year	$ 10,027	$ 117

See accompanying notes

1. SUMMARY OF ACCOUNTING POLICIES

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd.

Goodwill and other intangible assets

Effective January 1, 2002, the Company adopted, on a prospective basis, the new recommendations of the Canadian Institute of Chartered Accountants (the "CICA") with respect to valuation of goodwill and other intangible assets. Under the new recommendations, goodwill and intangible assets with an indefinite life will no longer be amortized, but will be tested for impairment at least on an annual basis. Intangible assets with definite lives will continue to be amortized over their useful lives and tested for impairment when conditions indicate the carrying value may not be recoverable in its entirety. The application of these new recommendations had no impact on the net income or financial position of the Company in the current or prior years.

Stock-based compensation

Effective January 1, 2002, the Company adopted the new recommendations of the CICA Handbook section 3870, Stock-Based Compensation and Other Stock-Based Payments. This section establishes standards for the recognition, measurement and disclosure of stock-based compensation and other stock-based payments made in exchange for goods and services. It requires that all stock-based awards made to non-employees be measured and recognized using a fair value based method. The standard encourages the use of a fair value based method for all awards granted to employees, but only requires application of specified accounting methods to direct awards of stock, stock appreciation rights, and awards that call for settlement in cash or other assets. If an alternative other than the fair value based method is used, pro-forma fair valued based information must be disclosed. The Company does not have any plans which result in the direct award of stock, stock appreciation rights and awards that call for settlement in cash or other assets and will continue to use the intrinsic value based method to account for stock-based compensation transactions with employees.

The Company has one stock-based compensation plan, which is described in Note 11. In 2002, 68,500 options were issued at an average exercise price of $13.50. If the Company had used the fair-value based method to account for stock-based compensation, pro forma net income and earnings per common share would have been as follows:

(Dollar amounts in thousands, except per share amounts)		2002
Net income	As reported	$ 4,590
	Pro forma	$ 4,488
Net income applicable to common shares	As reported	$ 4,253
	Pro forma	$ 4,151
Basic earnings per common share	As reported	$ 1.20
	Pro forma	$ 1.17
Diluted earnings per common share	As reported	$ 1.18
	Pro forma	$ 1.15

The following is a summary of the significant assumptions used in measuring the Company's pro-forma earnings and earnings per share:

	2002
Risk free interest rate	3 percent
Expected volatility (annualized)	44 percent
Expected years of option life (average)	7 years
Expected annual rate of dividends	4 percent

1. SUMMARY OF ACCOUNTING POLICIES (cont'd)

The Company has not included those options outstanding at the date of adoption in its assessment of the pro-forma impact of adopting this standard.

Regulation

The Company and Pacific Northern Gas (N.E.) Ltd. are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission"). During the year, the Commission issued a decision to set permanent rates for 2002 below the interim rates established at the beginning of the year. The effect of the reduction in rates, as well as the disallowance of other costs resulting from the decision, would have reduced previously reported earnings for 2001 by $301,000, net of tax.

Revenue recognition

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues that are recorded as service is provided.

Cash and short-term investments

Cash and short-term investments are held for the purpose of meeting short-term cash commitments and includes bank balances and term deposits with maturities of less than 90 days.

Inventories of supplies and natural gas

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

Plant, property and equipment

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. As directed by the Commission, the cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are 2.9% [2001 - 2.8%] for transmission plant, 2.6% [2001 - 2.6%] for distribution plant, 5.6% [2001 - 5.0%] for general plant and 4.8% [2001 - 4.7%] for processing plant. Application of these rates for the year ended December 31, 2002 resulted in a composite rate of 3.0% [2001 - 3.0%].

Deferred charges

[a] Debt expense

Debt expense comprises issue costs of long-term debt, which are amortized on a straight-line basis over the term of the related issue.

[b] Gas purchase variance recoverable (payable)

As directed by the Commission, gas purchase variance costs, which arise due to unanticipated commodity cost and demand fluctuations, are being charged or credited to cost of sales on a straight-line basis over periods ranging from one to three years. The amount of such credits to cost of sales in 2002 was $1,254,000 before tax [2001 - charge of $3,947,000].

[c] Pipeline rehabilitation costs

As directed by the Commission, pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. In 2001, pursuant to Commission approval, additional amortization of $800,000 was taken on outstanding pipeline costs to improve the cash flow and liquidity of the Company. The total amount of amortization of pipeline rehabilitation costs in 2002 was $204,000 [2001 - $1,354,000].

[d] Large Industrial Customer Margin Deferral

As directed by the Commission, a deferral account was set up to recover the lost margin from certain large industrial customers whose demand fell short of expectations. Total costs of $230,000 (2001 - $505,000) were deferred and included in other deferred charges. These amounts will be amortized commencing in 2003. The Company has applied to the Commission for a one-year amortization period of the deferral.

[e] Other

As directed by the Commission, various other costs have been deferred to be recovered from future revenues over periods ranging from 1 to 5 years. During 2002, $1,075,000 [2001 - $206,000] was charged to income in respect of these deferred costs.

Income taxes

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

Employee future benefit plans

The Company uses the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission. The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value and obligations are discounted using a current market interest rate.

The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 14 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

Financial instruments

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

Comparative figures

Certain of the prior year figures have been reclassified to conform to the current year's presentation.

2. MAJOR CUSTOMERS

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

(Percent)	2002		2001	
	Energy	Operating revenues	Energy	Operating revenues
Methanex Corporation	65	19	45	15
Skeena Cellulose Inc., Eurocan Pulp & Paper Co., Alcan Inc. and British Columbia Hydro and Power Authority	9	6	24	10

At December 31, 2002, 10% [2001 - 20%] of accounts receivable was attributable to these five customers.

3. PLANT, PROPERTY AND EQUIPMENT

(Dollar amounts in thousands)	2002	2001
Transmission plant	$ 175,578	$ 172,794
Distribution plant	80,929	78,870
General plant	19,491	18,580
Processing plant	512	470
Construction in progress	603	560
Total plant, property and equipment	277,113	271,274
Accumulated depreciation		
Transmission plant	64,399	59,587
Distribution plant	25,821	23,860
General plant	9,224	8,290
Processing plant	355	236
Total accumulated depreciation	99,799	91,973
	$ 177,314	$ 179,301

During the year, the Company received contributions in aid of construction of $85,000 [2001 - $385,000], which have been recorded as a reduction of distribution plant.

4. INCOME TAXES

Significant components of the Company's deferred tax liabilities are as follows:

(Dollar amounts in thousands)	2002	2001
Deferred income tax liabilities		
Capital cost allowance claimed for income tax purposes		
in excess of depreciation and amortization	**$ 14,462**	$ 14,462
Other	**991**	738
Deferred income tax liabilities	**$ 15,453**	$ 15,200

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

(Percent)	2002	2001
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	**39.6**	44.6
Increase (decrease) in income taxes resulting from:		
Large corporations tax	**2.9**	2.7
Depreciation in excess of capital cost allowance	**5.9**	5.5
Amortization of intangibles	**5.9**	9.5
Deferred charge expenditures deducted (added) for tax purposes	**1.1**	(7.3)
Other items	**4.7**	(3.9)
Effective rate of income taxes	**60.1**	51.1

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the asset and liability methodology been followed continuously since the inception of the Company, the additional deferred income tax liabilities and deferred income tax expense (recovery) would be:

(Dollar amounts in thousands)	2002	2001
Deferred tax liabilities – long term, beginning of year	**$ 15,250**	$ 15,679
Deferred income tax recovery	**(166)**	(429)
Deferred tax liabilities – long term, end of year	**$ 15,084**	$ 15,250

5. PENSION PLANS

The Company and its subsidiary have defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees.

Information about the defined benefit pension plans is as follows:

(Dollar amounts in thousands)	2002	2001
Accrued benefit obligations		
Balance, beginning of year	$ 13,154	$ 13,226
Current service cost	427	432
Prior service cost	–	6
Employees' contributions	14	21
Interest cost	947	931
Benefits paid	(1,026)	(564)
Actuarial losses (gains)	1,807	(898)
Balance, end of year	15,323	13,154
Plan assets		
Fair value, beginning of year	10,433	14,662
Actual return on plan assets	3,214	(4,239)
Employer contributions	367	553
Employees' contributions	14	21
Benefits paid	(1,026)	(564)
Fair value, end of year	13,002	10,433
Funded status – plan deficit	(2,321)	(2,721)
Unamortized net actuarial losses	2,356	2,763
Unamortized past service costs	3	5
Unamortized transitional asset	(22)	(20)
Accrued benefit assets	$ 16	$ 27

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

(Percent)	2002	2001
Discount rate	6.50	7.25
Expected long-term rate of return on plan assets	7.75	8.50
Rate of compensation increase	3.25	3.25

The Company's net defined benefit pension plan expense is as follows:

(Dollar amounts in thousands)	2002	2001
Current service cost	$ 427	$ 432
Interest cost	947	931
Expected return on plan assets	(987)	(1,137)
Amortization of past service costs	–	1
Amortization of transitional asset	(9)	2
Net defined benefit pension plan expense	$ 378	$ 229

The pension expense for the years ended December 31, 2002 and 2001 was $453,000 and $382,000, respectively.

The non-pension benefit plan is unfunded and had an unrecognized accrued benefit obligation of $3,099,000 at December 31, 2002 [December 31, 2001 - $2,093,000]. Payments made during the year for non-pension benefits, which are accounted for on a pay-as-you-go basis, were $71,000 [2001 - $48,000]. Had the accrual methodology been followed for non-pension benefits, pension expense would have increased by $277,000 [2001 - $302,000].

6. EARNINGS PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per common share are calculated using an adjusted average number of common shares outstanding during the year that reflect the potential exercise of dilutive share purchase options.

There are 102,700 [2001 - 115,920] stock options outstanding that could potentially dilute basic earnings per share in the future but were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

(Dollar amounts in thousands, except per share data)	2002	2001
Net income applicable to common shares		
– basic and diluted	$ 4,253	$ 5,377
Weighted average number of common shares outstanding		
– basic	3,553,445	3,547,780
Effect of dilutive stock options (shares)	37,930	16,361
Weighted average number of common shares outstanding		
– diluted	3,591,375	3,564,141
Earnings per common share		
– basic	$ 1.20	$ 1.52
– diluted	$ 1.18	$ 1.51

7. BANK INDEBTEDNESS

(Dollar amounts in thousands)	2002	2001
Bank demand operating line of credit	$ –	$ 8,675

The Company has a bank demand operating line of credit of $20 million [2001 - $20 million] which bears interest at bankers' acceptance rates [December 31, 2002 - 5.8%; December 31, 2001 - 5.23%] and provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. The line of credit is collateralized by the pledge of a $20 million debenture and a charge on certain accounts receivable and inventories. At December 31, 2002, the amount available under the facility was approximately $8.7 million, none of which had been drawn.

8. LONG TERM DEBT

(Dollar amounts in thousands)	2002	2001
Secured Debentures [a]		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate [December 31, 2002 - 5.793%], payable in monthly instalments of $110,000, with a final instalment of $120,000 at maturity.	$ 10,680	$ 12,000
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate [December 31, 2002 - 6.293%], payable in monthly instalments of $105,000, with a final instalment of $2,505,000 at maturity.	15,000	–
2011 Series, 10.75% due December 13, 2011, payable in annual instalments of $700,000, and $800,000 in each of years 2009 and 2010 with a final instalment of $5,000,000 at maturity.	10,800	11,500
2018 Series, 8.75% due November 15, 2018, payable in annual instalments of $600,000, commencing November 15, 1999 and $1,000,000 in each of the years 2014 to 2017, with a final instalment of $7,000,000 at maturity.	17,600	18,200
2025 Series, 9.30% due July 18, 2025, payable in annual instalments of $500,000, commencing July 18, 2004 with a final instalment of $9,500,000 at maturity.	20,000	20,000
2027 Series, 6.90% due December 2, 2027, payable in annual instalments of $500,000, commencing December 2, 2006 with a final instalment of $9,500,000 at maturity.	20,000	20,000
Construction advances and other [b]	523	489
	94,603	82,189
Long term debt due within one year	4,379	2,650
	$ 90,224	$ 79,539

[a] Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.

[b] Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.

[c] Payments required to meet sinking fund and retirement provisions during the next five years are as follows:

(Dollar amounts in thousands)	
2003	$ 4,379
2004	4,386
2005	4,386
2006	4,886
2007	4,886

9. PREFERRED SHARES

(Dollar amounts in thousands)		2002	2001
Authorized			
9,017	Cumulative redeemable junior preferred shares with a par value of $10		
200,000	6.75% cumulative redeemable preferred shares with a par value of $25 each		
Issued			
200,000	6.75% preferred shares	$ 5,000	$ 5,000

The 6.75% preferred shares are redeemable at the option of the Company at $26 per share plus any accrued and unpaid dividends at the date of redemption.

10. COMMON SHARES

(Dollar amounts in thousands)		2002	2001
Authorized			
6,000,000	Class A non-voting common shares with a par value of $2.50 each		
20,000	Class B voting common shares with a par value of $2.50 each		
Issued			
3,559,080	Class A common shares [2001 - 3,527,780]	$ 8,898	$ 8,819
20,000	Class B common shares	50	50
		$ 8,948	$ 8,869

During 2002, the Company issued 31,300 Class A common shares [2001 - nil] for cash consideration of $220,000 upon the exercise of employee options. Of this amount, $141,000 has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

On December 12, 2002 the Company declared a special common dividend of $2.75 per share payable on January 23, 2003.

11. STOCK OPTION PLAN

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2002, 423,100 [2001 - 266,460] shares are reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

A summary of the status of the Company's stock option plan as of December 31, 2002 and 2001, and changes during the years ending on those dates is presented below:

	2002		2001	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price
Outstanding at beginning of year	223,020	$ 13.98	132,360	$ 20.24
Granted	68,500	13.50	107,100	7.19
Exercised	(31,300)	7.00	–	–
Forfeited	(8,620)	14.60	(16,440)	20.14
Expired	(4,600)	14.13	–	–
Outstanding at end of year	247,000	$ 10.71	223,020	$ 13.98
Options exercisable at end of year	112,610	$ 17.59	102,032	$ 19.15
Weighted average remaining contractual life	7.2 years		7.3 years	

	Options outstanding 2002		Options exercisable 2002	
Expiry date	Number of shares	Exercise price	Number of shares	Exercise price
May 4, 2003	4,600	$ 15.75	4,600	$ 15.75
November 7, 2005	19,400	20.00	19,400	20.00
March 14, 2006	13,200	18.75	13,200	18.75
March 14, 2007	12,700	20.75	12,700	20.75
March 24, 2008	11,500	30.50	11,500	30.50
March 11, 2009	14,700	24.50	11,760	24.50
March 16, 2010	26,600	15.50	15,960	15.50
March 21, 2011	42,900	7.85	10,140	7.85
April 27, 2011	32,900	6.50	6,650	6.50
March 15, 2012	33,500	13.50	6,700	13.50
July 4, 2012	35,000	13.50	–	13.50
	247,000		112,610	

12. RELATED PARTY TRANSACTIONS

The Company's transactions with related parties are as follows:

(Dollar amounts in thousands)	2002	2001
Westcoast Energy Inc., parent company		
Transportation services received	$ 834	$ 828
Materials purchases and services received	588	567
Centra Gas British Columbia Inc., a company related through common control until December 31, 2001		
Materials purchases and services received	–	30
Enlogix CIS L.P., a company related through common control until September 5, 2002		
Services received	510	612
Duke Energy Marketing LP, an entity related through common control since March 14, 2002		
Natural gas purchases	2,034	–
Engage Energy Canada, L.P., an entity related through common control		
Natural gas purchases and services received	5,323	144
Natural gas sales	15,110	24,736

Accounts payable and accrued liabilities as at December 31, 2002 include $5,014,000 [2001 - $243,000] and accounts receivable at December 31, 2002 include $4,364,000 [2001 - $705,000] relating to the above related party transactions.

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties.

On March 14, 2002, all of the issued and outstanding common shares of Westcoast Energy Inc., the holder of all of the Company's voting shares, were acquired by an indirect wholly owned subsidiary of Duke Energy Corp.

13. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

(Dollar amounts in thousands)	Carrying value 2002	Carrying value 2001	Fair value 2002	Fair value 2001
Long term debt	$ 94,603	$ 82,189	$ 89,402	$ 61,631

The fair value of the Company's long-term debt is estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, gas purchase variance recoverable, bank indebtedness, and accounts payable and accrued liabilities approximate their carrying values.

14. NATURAL GAS AND INTEREST RATE CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices.

At December 31, 2002, the Company had outstanding call options with a related party covering approximately 2.25 million gigajoules of natural gas to be delivered in the months of January and February 2003 (representing approximately 19 percent of its forecast 2003 system gas supply) at strike prices ranging from $7.75 to $8.20 per gigajoule.

At December 31, 2001, the Company had entered into natural gas fixed price contracts to fix the price for approximately 1.3 billion cubic feet or 12 percent of its forecast 2002 system gas supply.

The difference between the price of gas used for toll purposes and the actual cost of gas purchased, including call option premiums, is deferred and refunded to or recovered from customers as directed by the Commission.

The call options outstanding had a fair value of $ nil at December 31, 2002. The fair value reflects the estimated amount that the Company would receive at December 31, 2002 on disposal of the call options. The fixed price contracts had a fair value of $260,000 payable at December 31, 2001. The fair value reflects the estimated amounts that the Company would pay at December 31, 2001 to terminate the fixed price contracts, based on the estimated future net cash flows under the terms of each contract.

The Company's purchase commitments at December 31, 2002 under various gas supply contracts expiring through 2005 were as follows:

(Dollar amounts in thousands)	
2003	$ 4,341
2004	4,851
2005	4,387

Tolls for customers of Pacific Northern Gas (N.E.) Ltd. are predicated on $8,000,000 of long-term debt financing. Accordingly, the Company is party to an interest rate swap contract that converts the interest rate characteristics of $8,000,000 of short-term borrowings from floating to a fixed rate of 7.7% until June 2004. The swap contract has a fair value of $549,000 payable at December 31, 2002 [$798,000 payable at December 31, 2001]. The fair value represents the amount the Company would have to pay to terminate the swap contract at December 31, based on the quoted market prices for similar instruments.

These estimated fair market values have no impact on earnings [see also note 13] due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

15. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes:

(Dollar amounts in thousands)	2002	2001
Accounts receivable	$ 393	$ 6,549
Gas purchase variance recoverable	–	4,487
Income taxes recoverable	–	3,566
Inventories of supplies and natural gas	155	999
Prepaid expenses	580	142
Accounts payable and accrued liabilities	3,241	(19,296)
Gas purchase variance payable	2,678	–
Income and other taxes payable	(8,823)	8,623
Attributable to operating activities	$ (1,776)	$ 5,070

Included in accounts payable and accrued liabilities at December 31, 2002 are dividends payable of $9,852,000 [2001 - $169,000].

Interest and tax payments:

(Dollar amounts in thousands)	2002	2001
Income taxes paid	$ 15,136	$ 681
Interest paid	7,289	9,768

16. SEGMENTED INFORMATION

The Company operates in one industry segment, the natural gas transmission and distribution segment, within Canada. The consolidated financial statements have therefore not been segmented.

Years ended December 31 (Dollar amounts in thousands, except for per share data)	2002	2001	2000	1999
Deliveries (TJ)				
Residential	3 503	3 470	4 216	4 202
Commercial	2 967	2 936	3 543	3 108
Small Industrial	3 805	3 592	3 875	3 694
Large Industrial	29 188	21 783	23 137	31 573
	39 463	31 781	34 771	42 577
Customers at year end	39,254	39,230	39,665	39,238
Average rates per GJ				
Residential	$ 8.62	$ 11.31	$ 8.20	$ 6.16
Commercial	7.49	10.16	5.96	4.84
Revenue				
Residential	$ 30,204	$ 39,239	$ 34,557	$ 25,881
Commercial	22,395	29,827	21,115	15,036
Small Industrial	9,479	10,539	9,349	6,356
Large Industrial	27,551	33,371	36,108	29,967
Off-System	18,763	24,736	14,108	–
Other	671	883	496	498
	109,063	138,595	115,733	77,738
Expenses				
Cost of Sales	56,820	83,344	61,750	24,778
Operating	23,423	24,189	23,297	22,876
Interest	7,642	8,797	9,293	9,050
Depreciation & amortization	9,653	10,581	8,866	8,094
Income taxes	6,935	5,969	5,689	5,815
	104,473	132,880	108,895	70,613
Net income	$ 4,590	$ 5,715	$ 6,838	$ 7,125
Per Common Share				
Earnings	$ 1.20	$ 1.52	$ 1.83	$ 1.92
Dividends paid	–	–	0.56	1.12
Capitalization				
Long-term debt	$ 90,224	$ 79,539	$ 82,158	$ 85,593
Deferred income taxes	15,453	15,200	15,653	12,789
Preferred shares	5,000	5,000	5,000	6,715
Common equity	68,966	74,345	68,968	64,311
	$ 179,643	$ 174,084	$ 171,779	$ 169,408
Utility Plant				
In service (net)	$ 176,711	$ 178,741	$ 182,016	$ 182,766
Construction in progress	603	560	1,335	151
	$ 177,314	$ 179,301	$ 183,351	$ 182,917

1998	1997	1996	1995	1994	1993
3 688	3 796	3 056	2 644	2 580	2 336
2 897	3 162	2 559	2 217	2 183	2 102
3 704	2 972	2 120	1 905	1 924	1 984
28 498	32 365	30 981	27 890	31 339	31 084
38 787	42 295	38 716	34 656	38 026	37 506
38,808	37,669	27,978	26,638	25,714	24,667
$ 5.80	$ 5.68	$ 4.90	$ 5.30	$ 5.31	$ 5.03
4.41	4.41	3.58	4.58	4.65	4.36
$ 21,380	$ 21,552	$ 14,971	$ 14,026	$ 13,708	$ 11,740
12,763	13,952	9,157	10,161	10,148	9,158
4,912	4,848	3,354	4,013	3,903	3,665
31,883	35,166	33,842	30,237	34,125	32,566
754	1,804	1,068	2,119	–	–
452	539	431	442	442	345
72,144	77,861	62,823	60,998	62,326	57,474
20,887	27,295	14,975	19,943	22,281	20,390
20,615	19,877	16,611	16,518	16,527	16,143
9,307	8,903	8,822	8,915	7,918	7,781
8,322	7,067	6,792	5,646	4,969	4,420
6,559	6,793	8,238	3,785	4,030	2,777
65,690	69,935	55,438	54,807	55,725	51,511
$ 6,454	$ 7,926	$ 7,385	$ 6,191	$ 6,601	$ 5,963
$ 1.73	$ 2.16	$ 2.01	$ 1.67	$ 1.80	$ 1.63
1.10	1.00	0.96	0.94	0.88	0.88
$ 88,894	$ 92,135	$ 74,862	$ 80,056	$ 63,990	$ 67,937
11,126	7,119	1,863	15,514	15,731	15,703
10,261	13,609	18,910	5,000	5,000	5,000
61,459	59,142	54,785	51,038	48,432	44,787
$ 171,740	$ 172,005	$ 150,420	$ 151,608	$ 133,153	$ 133,427
$ 178,614	$ 176,103	$ 156,995	$ 154,421	$ 145,047	$ 135,187
1,610	1,459	1,244	1,929	2,590	1,789
$ 180,224	$ 177,562	$ 158,239	$ 156,350	$ 147,637	$ 136,976

DIRECTORS

Robert F. Chase[1,2,4,5]
President and Chief Executive Officer
Lexacal Investment Corp.
West Vancouver, British Columbia

Roy G. Dyce[3,4]
President and Chief Executive Officer
Pacific Northern Gas Ltd.
Coquitlam, British Columbia

Hugh C. Morris[1,3]
Chairman
Eldorado Gold Corporation
Delta, British Columbia

Robert F. O'Shaughnessy[3,5]
Company Director
Galiano Island, British Columbia

David G. Unruh[1,2]
Senior Vice President and General Counsel
Duke Energy Gas Transmission Corp.
West Vancouver, British Columbia

Arthur H. Willms[2,4,5]
Director of Westcoast Energy Inc.
and Union Gas Ltd.
North Vancouver, British Columbia

[1] Audit Committee.
[2] Compensation Committee.
[3] Environment, Health and Safety Committee.
[4] Executive Committee.
[5] Corporate Governance Committee

OFFICERS

R.F. Chase
Chairman of the Board

R.G. Dyce
President and Chief Executive Officer

G.B. Weeres
Vice President, Operations and Engineering

S.G. De May
Vice President

C.P. Donohue
Director, Regulatory Affairs and Gas Supply

E.A. Fletcher
Treasurer and Comptroller

K. Stark Anderson
Secretary

L.A. Hodgins
Assistant Secretary

REGISTRAR & TRANSFER AGENT

Computershare Trust Company of Canada
Vancouver, Calgary, Regina, Winnipeg, Toronto, Montreal

AUDITORS

Deloitte & Touche LLP
Vancouver, British Columbia

ANNUAL MEETING

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at the Pacific Palisades Hotel, Hastings Room, Vancouver, British Columbia on April 17, 2003 at 10:00am (local time)

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